LNG Receiving Facilities

The receiving facilities would be located along either side of the FSRU, although only the starboard side initially would be outfitted to receive LNG carriers.[2] These facilities would consist of the on-deck loading arms, piping, and shutdown systems to allow safe transfer of LNG from the LNG carrier to the FSRU. Deck gear such as fenders, capstans (a type of winch for lifting heavy objects), and quick release hooks for LNG carriers' mooring lines would also be located on the deck. Fenders would prevent contact between the hulls of the FSRU and the LNG carrier during berthing and transfer procedures.

All loading arms would be identical, with 16-inch (0.4 m) diameters. They would be located approximately midship along the starboard side of the FSRU. Three of the four loading arms would receive LNG, while the fourth would return natural gas vapor displaced from the FSRU back to the LNG carrier. Vapor return arms are necessary because LNG, when transferred from one vessel to another, would cause the rising liquid (LNG) level in the receiving tanks to displace the volume available for the vapor already existing in these tanks (known as the piston effect); secondarily, the LNG being pumped into the receiving tanks would also generate additional vapors in the receiving tanks due to the agitation of the liquid during pumping and due to contact between a cold liquid and the relatively warmer empty upper part of the receiving tanks.

The rising liquid level in the receiving tanks would push the vapor out through the vapor return line at a controlled rate, and would be routed back to the source vessel's tanks to maintain balanced pressures. This "closed" cargo transfer arrangement confines all of the vapor within the system. Thus, the atmospheres above the tanks' liquid levels would always be 100 percent natural gas and (since no oxygen is present) non-flammable.

The mooring and loading arm systems would have emergency quick-release capability so that LNG transfer could be safely stopped and the LNG carrier safely released even if adequate weather warning were not received, such as during a quickly developing squall or when encountering wave heights greater than forecasted. When activated, the emergency quick-release actions would take less than one minute to complete.

The LNG carriers would have a capacity ranging from 2.6 million to 5.8 million gallons (100,000 to 220,000 m^3). The total LNG transfer rate through the starboard-side loading arms would be approximately 80,000 gallons (303 m^3) per minute (gpm), equivalent to 4.8 million gallons (18,180 m^3) per hour. Each LNG carrier berthing, unloading, and de-berthing event would last approximately 20 hours. The FSRU would receive LNG shipments approximately two to three times per week. Figure 2.3-2 shows the berthing arrangement during offloading operations. If the supply of LNG to the FSRU was interrupted for an extended period of time (dependent on the remaining level

[2] Currently, it is anticipated that only the single berth and loading facility on the starboard side of the FSRU would be used because no more than one carrier at a time would unload. The second berth, if added, would provide operational flexibility under unusual conditions and would never be used simultaneously. If added, the second berth will require a modification of the FSRU license.

of LNG in the tank(s) and the ambient temperature), resulting in the emptying of the three insulated, double-walled spherical Moss tanks (see section on LNG Storage Facilities below), there would be a small impact on operation of the FSRU. If the tanks were warmed to ambient temperature by the time the LNG supply resumed, an approximately 30-hour cool-down period for the tanks would be needed before onloading of the LNG could occur. The cool-down of the tank(s) would involve using a small quantity (i.e., several gallons) of LNG from the LNG carrier and spraying it on the interior walls of the tank(s).

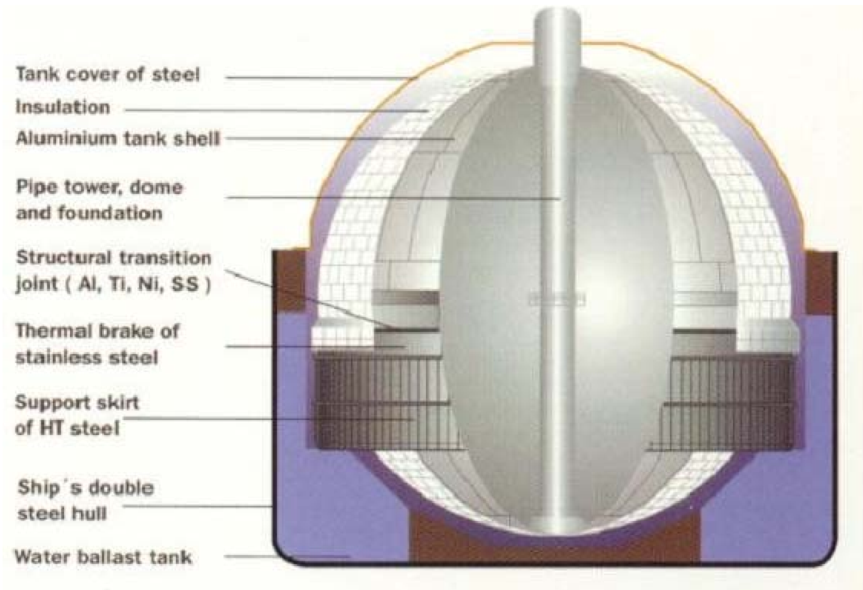
LNG Storage Facilities

The FSRU would store LNG in three Moss tanks. The Moss tanks would be located along the length of the facility, forward of the deckhouse/quarters and aft of the regasification equipment. A cross section of a Moss spherical tank is depicted in Figure 2.3-3. Each Moss tank would be 183.7 feet (56 m) in diameter and would have an LNG storage capacity of 24 million gallons (91,000 m^3). The total LNG storage capacity on the FSRU would be approximately 72 million gallons (273,000 m^3).

Each Moss tank would consist of an aluminum internal tank shell surrounded by layers of insulating material and would be supported on a steel skirt ring that would be braced inside the double hull of the FSRU. After installation of the tank in the FSRU, a steel weather cover would be constructed over the top of the tank to totally enclose the structure and provide for a gas-tight hold space around the cargo tank. Each Moss tank would be located in a separate cargo hold and mounted directly on the foundation deck inside the double hull of the FSRU; this design would provide significant barriers to tank breach and escape of liquid.

The normal tank operating pressure would be approximately atmospheric; however, the tanks would be designed for up to 30 pounds per square inch gauge (psig) (21,100 kilograms per square meter [kg/m^2]) of internal pressure. Automatic relief valves would reduce tank pressure if it was to exceed 3.5 psig (2,460 kg/m^2). Discharge from the relief valve(s) would be to the atmosphere through a vent mast located at the top of each tank.

No mechanical means of refrigeration would be required because LNG would be refrigerated (liquefied) at the sending site and transported in thermos-like tanks. The insulation on the Moss tanks would be designed to allow some of the liquid to warm over time and return to its gas form. By maintaining fairly constant tank pressures through removal of this “boil-off gas,” the remaining liquid cargo would be maintained in its cold liquid form by a physical process called auto-refrigeration (which requires no mechanical assistance). About 0.12 percent of the LNG would be allowed to boil off each day under normal conditions. The boil-off gas is not discharged but, rather, would be used either as a fuel supply for the electrical generators in the regasification process or diverted into the natural gas delivered to shore.



Key:
Al = Aluminum
Ti = Titanium
Ni = Nickel
SS = Stainless Steel
HT = High Tensile

Figure 2.3-3 Cross Section of Moss Tank

Nine LNG pumps, three per Moss tank, would be able to transfer up to 13,000 gpm (49,200 liters per minute [lpm]) of LNG from the storage tanks to the booster pumps located in the regasification facilities area. The same transfer rate could be achieved with only two of the pumps, thereby allowing maintenance without interrupting LNG transfer.

LNG Regasification Facilities

The regasification facilities area, located on the bow (front) of the FSRU just forward of the storage facilities, would include up to six LNG centrifugal booster pumps and eight submerged combustion vaporizers. The booster pumps would increase the pressure of the LNG to approximately 1,500 psig (1.05 million kg/m^2) before feeding the LNG to the submerged combustion vaporizers (submerged in fresh water) where the LNG would be regasified. The LNG would be vaporized and pass into the discharge manifold before being exported to shore via pipeline. This closed, high-pressure welded piping system would be designed and constructed to the required piping codes for high-pressure LNG service.

The eight submerged combustion vaporizers would each have a maximum LNG vaporizing capacity of 198 tons (179,626 kg) per hour. Any five of the eight submerged combustion vaporizer units would operate at 100 percent load throughout the year. The heater unit would be fueled by boil-off gas, and any boil-off gas not used for this purpose would be diverted back into the gas delivery system. The submerged combustion vaporizers would heat the LNG, resulting in regasification of the LNG into natural gas at a temperature of 41°F (5°C). The LNG and natural gas flow would be contained within process piping submerged in a water bath maintained at 86°F (30°C). The water bath would provide stable heat transfer from the LNG to the natural gas. The regasification process is shown in Figure 2.3-4. The normal regasification capacity would be between 579 and 821 tons (525,269 and 744,811 kg) per hour, and the maximum regasification capacity would be 1,450 tons (1,315,440 kg) per hour.

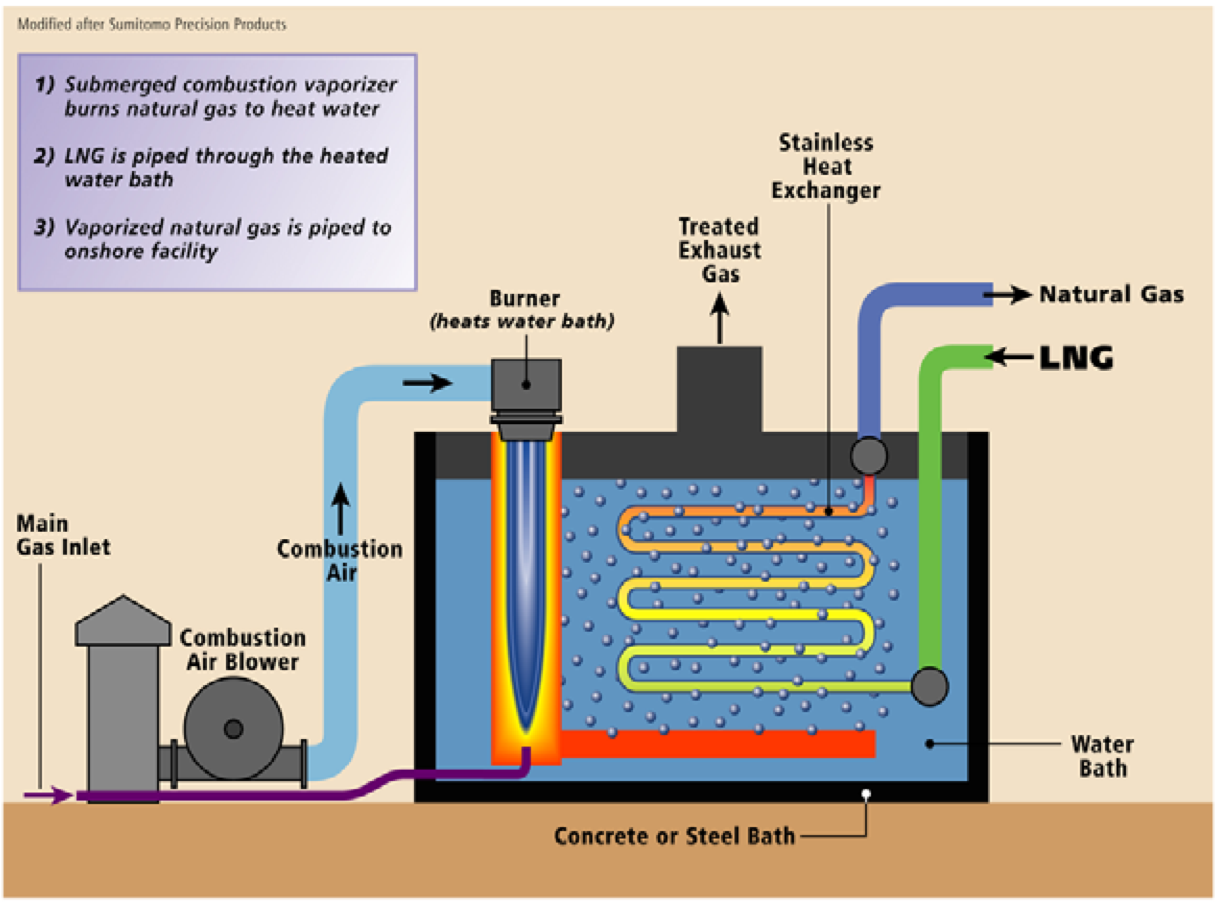


Figure 2.3-4 Submerged Combustion Vaporizer Process Schematic

Natural gas combustion would provide heat for regasification during the submerged combustion vaporizer process. No seawater would be used for the water bath. Fresh water for the water bath would be generated as a by-product of the combustion process in the submerged combustion vaporizer units, totaling 199,680 gallons (755,800 liters) per day with an average of five submerged combustion vaporizers operating simultaneously. Neither LNG nor natural gas would be directly released into the water bath, but combustion exhaust gas (mainly carbon dioxide and water vapor) would bubble through the water bath. The water in the bath consists of clean, distilled water; however, the bubbling of combustion gases through this water would cause the pH to drop, making the water slightly acidic. Therefore, any water discharged from the submerged combustion vaporizer operations would be treated to neutralize the pH for potable and non-potable use onboard or before discharge to the ocean.

Cold Venting

The regasification plant would be designed such that gas would be released to the atmosphere only during emergency or abnormal process situations. Two separate vent systems would be provided: one high pressure vapor system, which would handle releases from the LNG vaporizers and the high pressure boil-off gas compressor, and a low pressure vent, which would handle low pressure gas releases and liquid discharges from thermal relief valves and equipment drains. Any small liquid discharges would be caught in the low-pressure vent knock-out drum, where it would be regasified using an electric heater. The natural gas would then be safely vented through the stack, with further electrical heating, if necessary, to ensure proper dispersal to the atmosphere. In the event of an emergency, processing operations would be shut down and the electric heater would be kept running through the use of the emergency generator. The vent outlet would be elevated to the top of a vent stack to ensure adequate dispersion of vapors below the flammable concentration limit (see Section 4.2, “Public Safety”). No gas would ever be flared.

Natural Gas Metering

The two subsea pipelines running to shore would be fitted with independent flow meters, one onboard the FSRU and one onshore at the metering facility (i.e., at each end of the pipeline system) that would measure the flow through the individual pipelines and the cumulative flow through both pipelines such that if one meter were down the other would still measure the total flow.

2.3.1.4 Mooring and LNG Transfer

The FSRU would attach to nine anchor cables and four gas risers at its pivot point on the bow. This structure, a turret-style mooring point, would allow the FSRU to weathervane, or rotate 360°, depending on wind and wave conditions or by using the thrusters at the aft end of the hull. The mooring point would serve two purposes: to hold the FSRU in position through the anchor cables and to connect the flexible natural gas risers to the vessel for the export of natural gas.

Mooring System

The mooring position would be fixed using the nine cables and associated ocean-floor anchor points. The cables and anchor points would be arranged in three groups of three, separated from each other by 120° angles. The anchor cables would spread out from the mooring location to anchors located at a radial distance of approximately 0.75 miles (1.2 km). The anchor points would use conventional drag anchors.

Flexible Risers and Riser Pipeline End Terminations

The natural gas would flow through the turret mooring point and into the four 11-inch (0.3 m) diameter flexible risers that would extend from the mooring turret to the pipeline end terminations (PLETs) which, in turn, are connected to the PLEM, i.e., the entryway connecting the two subsea pipelines running to shore. Each riser would be anchored to the sea floor but would have sufficient flexibility to allow the mooring turret to move within the design range.

The flexible risers, while having all the pressure containment characteristics of equivalent steel pipe, would also have sufficient flexibility, length, and strength to allow the FSRU to move on its mooring system, even under extreme conditions, without risk of damage. The risers would be designed to withstand both maximum design operating pressure as well as 100-year storm conditions, even with one mooring cable broken.

The flexible risers would be equipped with redundant shutdown valves on each end. The mooring point end of each riser would have two valves in series: an isolation valve and an automated safety shutdown valve. Cross-connections between the four risers would also have isolation valves. The cross-connections would tie into each riser between the isolation valve and the shutdown valve. (Note: the only difference between an isolation valve and a shutdown valve is that the shutdown valve can be automatically shut down by the safety shutdown systems if an abnormal or dangerous condition is detected, whereas an isolation valve requires deliberate human intervention to open or close.) Similarly, the termination of the flexible risers at the sea floor would include shutdown valves and cross-connections. Any individual riser could be shut down and isolated for inspection, maintenance, or repair while natural gas transmission continued in the other three.

Pipeline End Manifold

The four flexible risers would interconnect to the subsea transmission pipelines via the PLETs through the prefabricated, skid-mounted PLEM. The PLETs would be located on the sea floor at a radius of approximately 557.7 feet (170 m) from the centerline of the mooring turret. The flexible pipe continuations of the risers would connect directly from the FSRU, via the PLETs, to the PLEM, which is anchored on the seabed; the PLEM would be connected to the subsea pipelines and the PLETs through two steel jumper pipes.

Each riser tie-in to the PLEM would be equipped with one shutdown valve and one isolation valve mounted in-series on the PLEM that are normally operated from the surface but that can be operated by a remotely operated vehicle (ROV) as a backup. The PLEM would also contain two 24-inch (0.6 m) diameter shutdown valves in series at the tie-in for the subsea transmission pipelines. All subsea safety shutdown valves would be hydraulically operated from the FSRU. All shutdown valves, no matter their locations, would be subject to automatic action and shutdown by the emergency shutdown system located on the FSRU. This system would take appropriate action if sensors detected abnormal or dangerous conditions. All subsea shutdown valves would be designed to fail in the closed position. In the event of loss of the hydraulic control cable, the affected shutdown valve would close and natural gas flow would be stopped.

2.3.1.5 Utilities Systems and Waste Management

Utilities would include electrical generation; heating, ventilation and air conditioning; water and wastewater management; hazardous materials management; and garbage collection, storage, and transfer equipment.

Power Generation

A utility area near the stern (back) of the FSRU would include the onboard electric power generation equipment. This power generation equipment would consist of four generators, including three natural gas-fired generator sets and one dual-fuel (natural gas/diesel fuel) generator set. Each of the four gas-fired units would have a power output of 7,400 kilowatts (kW) at 6.6 kilovolts (kV). The diesel fuel side of the dual-fuel unit would be used for emergency duty only.

All the required motor control centers, substations, cabling, and lighting systems would be arranged in accordance with applicable regulations and standards regarding protection, insulation, and general safety. All electrical equipment within hazardous zones would be designed, installed, and supplied with certificates to show that the equipment is intrinsically safe or explosion-proof.

Although one of the electrical generators would be capable of burning either natural gas, gas, or diesel, after LNG operations begin the diesel fuel would be retained for emergency fuel supply only. It would be used during emergency training drills and for monthly tests of the emergency generator and firefighting water pumps or for occasional tests of the dual fuel generator.

Fuel Gas

The Moss tanks would allow natural gas boil-off of 0.12 percent per day. The boiled off natural gas would be compressed and injected into the subsea pipelines or recovered and used as fuel for FSRU electric power generation. The boil-off gas compressor plant would require four compressors. Boil-off gas from vaporization of LNG would be used as the primary source of fuel for the FSRU and would fuel the main generator engines and the submerged combustion vaporizers. Because the quantity of boil-off gas would typically be insufficient to supply the FSRU, gas would also be taken from the vaporizer discharge header and used as fuel for the power generation equipment.

Diesel Fuel

The FSRU would be loaded with 264,000 gallons (1,000 m^3) of diesel fuel before departing from the fabrication shipyard. The fuel would be used for initial power generation needs during installation and commissioning until receipt of LNG. The diesel fuel would be stored in two steel, single-wall tanks located just forward of the main engine room. Each tank would be accessible from all outer sides to allow inspection. Secondary containment would consist of a drip tray with extended walls under each tank and associated equipment that would collect any leaks from valves and fittings. The diesel fuel supply would be replenished by transporting approximately 350-gallon (1,300 liter) capacity totes to the FSRU on the supply vessels, as needed, but generally would occur on a schedule of once per month. The totes would be offloaded onto a bermed area on the deck of the FSRU and pumped into the storage tanks. The empty containers would then be returned to shore via the supply vessel for reuse or disposal.

Hazardous Materials and Lubricants Management

Hazardous materials that would be used onboard the FSRU during normal operations include paints, fuels, solvents, urea, and caustic. In addition, lubrication oil would be stored onboard for use with various rotating equipment.

Incidental Paints and Solvents

FSRU maintenance activities would require the use of various paints, solvents, and other hazardous materials. These materials would be brought onboard in retail-size containers and stored in designated compartments specially designed and constructed for the storage of hazardous materials and paints. Empty containers would be hauled to shore for appropriate recycling or disposal.

Urea

The power generation equipment aboard the FSRU would be equipped with air emissions control equipment designed to reduce the emission of nitrogen oxides. Urea would be used in this process instead of aqueous or anhydrous ammonia because it is considered safer. The Material Safety Data Sheet (MSDS) for these materials identifies ammonia as having a “severe” health and contact rating, while urea is considered “moderate.” Also, urea is considered a skin irritant while ammonia can cause caustic burns. Urea can be transported as bagged solid pellets and mixed into an aqueous solution onboard and would be stored in dedicated tanks. Consequently, the use of dry urea reduces the inherent risk of handling aqueous or anhydrous ammonia in an offshore marine environment.

Lubricating Oils

The onboard mechanical equipment, including power generation units, boil-off gas compressors, LNG booster pumps, fire-fighting water deluge system pumps, and ballast water pumps would require holding an inventory of lubricating oil as periodic change-out of lubricating oil is necessary. Replacement oil would be brought onboard in 55-gallon (210 liter) drums or 350-gallon (1,300 liter) totes. Used oil would be returned to shore in the same containers used to provide the replacement oil. Used oil would be managed, disposed of, or recycled in accordance with U.S. Environmental Protection Agency (USEPA) and State requirements. All oil would be managed in accordance with the facility-specific Spill Prevention, Control, and Countermeasures (SPCC) Plan.

2.3.1.6 Safety Systems

Emergency equipment would include systems for hazard detection, emergency shutdown, spill containment, fire protection, flooding control, crew escape, and all other such systems and equipment required by the USCG and other applicable regulatory agencies. These requirements are discussed in more detail in Section 4.2, "Public Safety."

The entire plant would be highly instrumented and monitored/controlled from the central control room located in the deckhouse. It would be protected by extensive safety systems, including fire and gas detection, fire-fighting systems, a shutdown system, and a blowdown system.

Integrity of the entire plant would be assured through a formal and documented inspection and maintenance program. Vessels, pumps, piping, and instruments would be inspected and maintained at regular intervals, which would be specified at the design stage. All maintenance operations would be performed under strict guidelines designed to minimize releases and to ensure the safety of the system and personnel. In most aspects, routine storage, regasification, and maintenance operations would be similar to those associated with existing onshore LNG regasification facilities.

Hazard Detection and Emergency Shutdown Systems

The FSRU would be equipped and designed to provide a high level of protection to personnel, the unit itself, and the environment against the effects of an uncontrolled release of hydrocarbons or other process gases. The FSRU would be designed to separate the process area from the accommodation area. Likewise, the Moss tanks, mooring, and risers would be separate from the process area. The outer shell of the forward tank (adjacent to the process area) would be fitted with a special barrier as part of the tank's weather cover to provide enhanced protection against fires or other potentially dangerous process area incidents.

Emergency Shutdown (ESD)

The facility, including the FSRU, pipelines, onshore facilities, and berthed LNG carrier, would be protected by comprehensive emergency shutdown systems. These would be electronic, high integrity, redundant systems that would initiate a range of shutdown actions, with the course of action depending on the nature and severity of the cause for shutdown. The type of shutdown system would include electronic detection devices, thermal fusible plugs, and pneumatic pipe loops, which would automatically activate a range of shutdown scenarios. Manually activated shutdown initiators at various locations, including the facility's control room, would complement these.

Fire- and gas-detection devices would also be located at strategic locations throughout the facility, including the Moss tank domes, loading arm areas, and the regasification facility. The status of the fire and gas system would be reported on a monitoring panel and the integrity of the complete system would be maintained by frequent and regular testing.

ESD comprises multiple levels of action from the shutdown of individual equipment shutdown, to shutdown of a system or area, to an overall facility shutdown. Where appropriate, the shutdown systems would initiate loading arm and mooring line release mechanisms, which would initiate the departure of the LNG carrier.

Emergency Depressurizing and Venting System

The FSRU would be equipped with a cold stack to vent natural gas vapors in the event of an emergency. The cold stack would be provided with an electric heating system to vaporize any emergency LNG releases and, if used, would discharge natural gas to the atmosphere without a pilot light or other device to initiate combustion. The cold stack height, pending final design, would be approximately 250 feet (76 m) above the waterline and approximately 80 feet (24 m) above the top of the storage tanks, elevated personnel walkway, and elevated piping along the tops of the tanks. These specifications would allow safe dispersal of the natural gas, considering the presence of the FSRU and an adjacent LNG carrier.

Gas Detection Systems

The FSRU would be equipped with a stationary gas detection system consisting of continuously operating catalytic type detectors and infrared line-of-sight detectors connected to the FSRU's electronic fire and gas panel. The gas-detection system would sound audible alarms as well as initiate the shutdown of appropriate equipment and systems. Gas detection would be provided for the regasification plant, other deck areas, machinery spaces where high-pressure gas is piped, and the ventilation air inlets to safe spaces, including personnel accommodation areas.

Fire Protection Systems

Depending upon the location and type of fire, different firefighting systems would be used. These would include a main seawater deluge system to contain a gas fire and to avoid ignition in case of gas releases; a dry chemical powder system for LNG fires; a low expansion foam system for process deck areas, machinery and oil storage spaces; a carbon dioxide (CO_2) fire suppression system for machinery spaces, paint lockers, and all flammable materials storage areas; and a conventional sprinkler system for living quarters plus supplemental fire extinguishers stationed at multiple locations around the FSRU.

Spill Containment System

Secondary containment would be designed for areas with the greatest risk of LNG release, such as the loading arm area, and would have two main functions: (1) to safely contain any releases from the primary containment (tanks and loading manifold area) and (2) to safely protect the FSRU from potential damage from exposure to cryogenic temperatures. Spill containment would be designed in accordance with the codes and standards applicable to LNG carriers and terminals, including a SPCC Plan, as required for deepwater ports under 40 Code of Federal Regulations (CFR) 112.1(a).

Natural Gas Purging with Inert Gas

Nitrogen would be used when necessary to purge natural gas from FSRU gas-related equipment. This is a safety procedure. The use of nitrogen and/or other inert gas to purge areas that may have undesired concentrations of natural gas is a standard industry practice. The process prevents the introduction of air that, when mixed with residual natural gas, could result in a mixture within its flammable limits. Nitrogen would be generated onboard the FSRU using a process that separates nitrogen from the ambient air.

2.3.1.7 Other Operations

Equipment/Supplies/Personnel Transfer Area

The aft-most part (i.e., back) of the FSRU would be equipped with a crane and basket to transfer supplies, parts, other needed items, and personnel to/from the FSRU and from/to supply vessels and to offload garbage, hazardous wastes (e.g., waste oil), and other items as needed for disposal on shore. A large floating fender would be deployed from the stern to prevent damage to the FSRU and the supply boats.

Helicopter Landing Area

A helicopter landing area would be located on the stern of the FSRU, above and behind the deckhouse. This pad would be intended only for limited use (mainly for visitors and during emergencies). No aircraft refueling facilities or helicopter fuel would be located onboard the FSRU.

Deck House

Located behind the Moss tanks and just forward of the landing area on the front of the FSRU, the deckhouse would have facilities to accommodate a permanent crew of up to 50. For safety reasons, all living, dining, and recreation spaces would be contained in this deckhouse to separate the processing area from the accommodation area.

Command and control facilities, including monitoring and control instrumentation for LNG/natural gas process activities, ballast system, communications, radar equipment, electrical generation, emergency systems, and thruster controls, would be located in a central control room in the deck house. A command bridge space, located at the top of the deck house above the crew accommodations, would serve as a backup location for the command and control functions and would be primarily used during docking/undocking and other marine traffic-related operations.

2.3.1.8 Safety Zone and Precautionary Area

Under Federal law (33 CFR 165.2 Subpart C, Safety Zones), a safety zone is an area “to which, for safety or environmental purposes, access is limited to authorized persons, vehicles, or vessels. It may be stationary and described by fixed limits or it may be described as a zone around a vessel in motion.”

However, according to the United Nations Convention on the Law of the Sea and the Continental Shelf Act of 1964 (No. 28 of 3 November 1964, as amended by the Continental Shelf Act Amendment Act, No. 17 of 14 November 1977), a safety zone can only extend to 0.27 NM (0.3 miles or 500 m) as “measured from each point of the outer edge of the installation or device, around any such installations or devices in, on, or above the continental shelf.” Several Outer Continental Shelf platforms offshore California have 0.27 NM (500 m) safety zones established pursuant to 33 CFR 147 (see Section 4.3.2, “Marine Traffic, Regulatory Setting”).

The Applicant has requested a safety zone with a radius of 0.27 NM (0.3 miles or 500 m) from the outer edge of the FSRU. The Applicant has also requested a 2 NM (2.3 mile or 3.7 km) radius from the outer edge of the FSRU as a precautionary zone, for an area of 16.6 square miles (43 km^2); and the USCG, in accordance with Rule 10 of the International Regulations for Preventing Collisions at Sea, 1972 (COLREG 1972), as amended, can petition the IMO to establish an area to be avoided. The USCG would determine the size of the area to be avoided if the DWP license is approved.

If the DWP license were approved, the safety zone and area to be avoided would be added to navigation charts. The safety zone is a limited access area only, established in accordance with 33 CFR Part 150. Only LNG carriers bound for the FSRU and service and supply vessels associated with the FSRU and LNG carrier operations (i.e., activities compatible with the deepwater port) would be allowed to enter the safety zone. The USCG would publish a Notice to Mariners, in English, advising mariners of this limitation. The area to be avoided is only a recommendation. Vessels are advised to seek alternative routes outside the area to be avoided but are not restricted from entering the area.

The Applicant has proposed approach routes to the FSRU: one of the four routes may use the Los Angeles – Long Beach traffic separation scheme (TSS), beginning in the Gulf of Santa Catalina, passing through the precautionary area off the entrances to Los Angeles and Long Beach harbors, and then continuing into the San Pedro Channel TSS. The USCG, through its review of the Operations Manual, would approve or deny any proposed routes that may be requested for inclusion.

2.3.2 Offshore Pipelines and Associated Facilities

The Project would include two parallel 24-inch (0.6 m) diameter subsea gas transmission pipelines to deliver the natural gas from the FSRU to a new onshore interconnect that would be owned and operated by SoCalGas. The total length of the pipelines from the pipeline-ending manifold to the SoCalGas main line valve would be approximately 18.7 NM (21.5 miles or 34.6 km). The twin pipelines, which would be laid approximately 100 feet (30 m) apart (i.e., 50 feet [15 m] on each side of the centerline), would be made of carbon steel and coated with an anti-corrosion coating. In addition, sections of the pipeline would be concrete-coated to prevent waves from moving the pipeline (in areas where necessary, based on information submitted by the Applicant and EIS/EIR analyses). Aluminum anode rings (called "bracelets") would be attached at regular spacing along the pipeline to provide cathodic corrosion protection. Finally, in areas where necessary, based on local conditions, stiffening ring elements (called "Buckle arrestors") would be attached to the pipeline at regular spacings to prevent the pipeline from collapsing under hydrostatic water pressure. Pipeline technical characteristics are presented in Table 2.3-1 below.

Table 2.3-1 Offshore Pipeline Characteristics

Parameter	Characteristic
Pipeline Length (each)	21.5 miles (34.6 km)
Outside Diameter	24.0 in. (0.6 m)
Wall Thickness	0.875 in. (2.2 centimeters [cm])
Steel pipe material grade	API 5L X60*
Steel pipe material density	490 lb/ft^3 (7,850 kg/m^3)

Key:
kg/m^3 – kilograms per cubic meter
lb/ft^3 – pounds per cubic foot

* American Petroleum Institute, January 2000, Recommended Practice 5L X60, Line Pipe, 42nd Ed.

The subsea transmission pipelines would originate next to the PLEM on the ocean floor below the mooring point and extend to shore. The offshore pipelines would be laid on the sea floor in waters deeper than 42.6 feet (13 m), as suggested by the U.S. Department of the Interior (DOI), Minerals Management Service (MMS). These depths occur approximately 3,000 feet (0.6 miles or 0.9 km) offshore. The subsea pipelines would cross three telecommunication cable crossings en route: the Navy RELI cable, the Navy FOCUS cable, and the Global West cable. Both of the Navy cables are buried beneath the seabed while the Global West cable is laid on the sea floor. These cables would be crossed using sandbags, concrete mats, or “sleepers” (i.e., fabricated steel pipe supports).

The Applicant’s initial proposal to install one 30-inch (0.9 m) diameter offshore gas pipeline was modified to two 24-inch [0.6 m] pipelines at the suggestion of CSLC staff to provide redundancy (during inspection or maintenance, natural gas can flow through one pipeline while the other one is being serviced) and to account for the capability of most pipe-laying barges, which handle steel pipe up to 24 inches (0.6 m) in diameter.

2.3.3 Shore Crossing

The subsea pipelines would come ashore and extend 0.65 mile (1.05 km) below the beach and terminate at the proposed meter station on the existing Reliant Energy Ormond Beach Generating Station to tie-in to the SoCalGas system. HDD technology would be employed to place the pipelines at least 35 feet (10.7 m) below the beach. The maximum depth below ground surface would depend on depth to sandstone, which is estimated between 50 and 75 feet (15 to 23 m), pending additional geotechnical studies and final design (see Section 2.4.3). Each of the two HDD shore approaches for the Project is expected to be between 4,500 to 5,000 feet (1,372 to 1,524 m) in length and would be parallel to each other, with approximately 100 feet (30 m) of separation, 50 feet (15 m) on each side of the centerline. The HDD staging area would be located on disturbed land. The presence of wetlands near the shore crossing is discussed in Section 4.8, "Biological Resources - Terrestrial."

A main-line valve at the SoCalGas facility would separate the Applicant's facilities from the SoCalGas facilities and would serve as an emergency shutdown valve that would automatically close to isolate flow between the transmission pipelines and the SoCalGas system in an emergency.

2.3.4 Onshore Pipelines and Aboveground Facilities

Two new pipelines would also be constructed on land: the Center Road Pipeline and the Line 225 Pipeline Loop. Figures 2.3-5 and 2.3-6 show the proposed pipeline routes.

2.3.4.1 Center Road Pipeline

The Project would include installation of approximately 14.3 miles (23.0 km) of new 36-inch (0.9 m) diameter pipeline with a maximum allowable operating pressure (MAOP) of 1,100 pounds per square inch (psi) (773,000 kg/m^2) to transport natural gas to the Center Road Valve Station. The new pipeline alignment would follow existing ROWs, public roads, and/or newly acquired easements. The proposed route is as follows:

- begin at the new metering station within the Reliant Energy Ormond Beach Generating Station;
- run north along the Southern California Edison (SCE) electric transmission line ROW;
- turn east on Hueneme Road, north on Naumann Road, west on Etting Road, and north on Hailes Road to Pleasant Valley Road;
- at Pleasant Valley Road the route would head southwest for approximately 1,000 feet (305 m) and then turn north through agricultural fields;
- continue through agricultural fields, cross 5th Street (Highway 34), continue north along Del Norte Boulevard, and cross Sturgis Road to U.S. Highway 101;
- turn east along U.S. Highway 101 frontage road, then turn north and cross U.S. Highway 101;
- proceed northeast to Central Avenue, then southeast along Central Avenue and northeast along Beardsley Road;
- head northeast for approximately 0.25 mile (0.4 km), then northwest along a flood control channel (the Santa Clara Diversion) to Santa Clara Avenue;
- follow Santa Clara Avenue northeast, then continue northeast at Los Angeles Avenue, north at La Vista Avenue, west at Center Road.
- terminate at the Center Road Valve Station.

Base map source: *Figure 5.7-1, Transportation – Center Road and Alternative Pipeline Routes,* Entrix, December 9, 2003

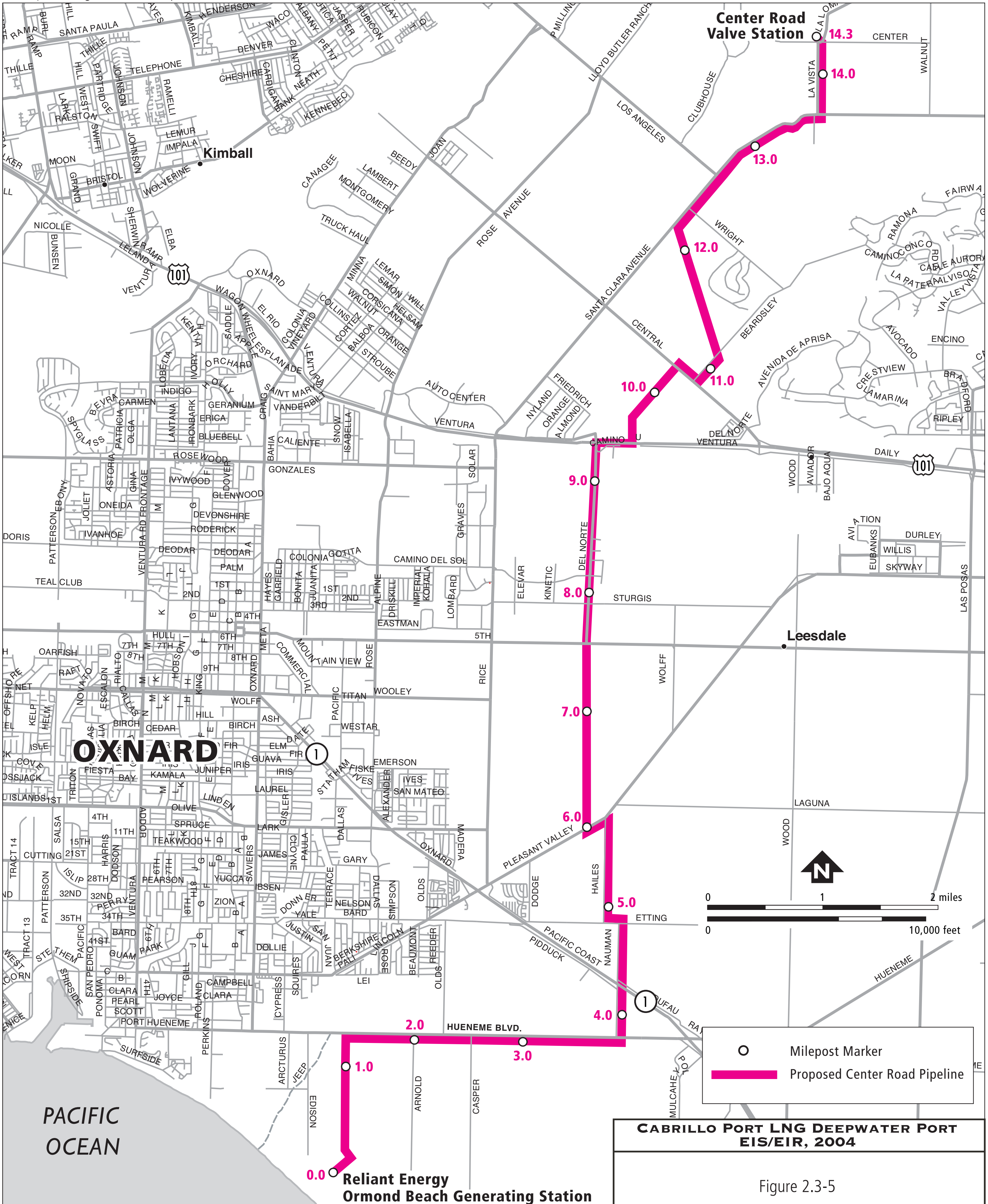


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Figure 2.3-5

Proposed
Center Road Pipeline Location

Base map source: *Figure 5.7-2, Transportation for the Line 225 Loop and Alternative Routes,* Entrix, May 3, 2004

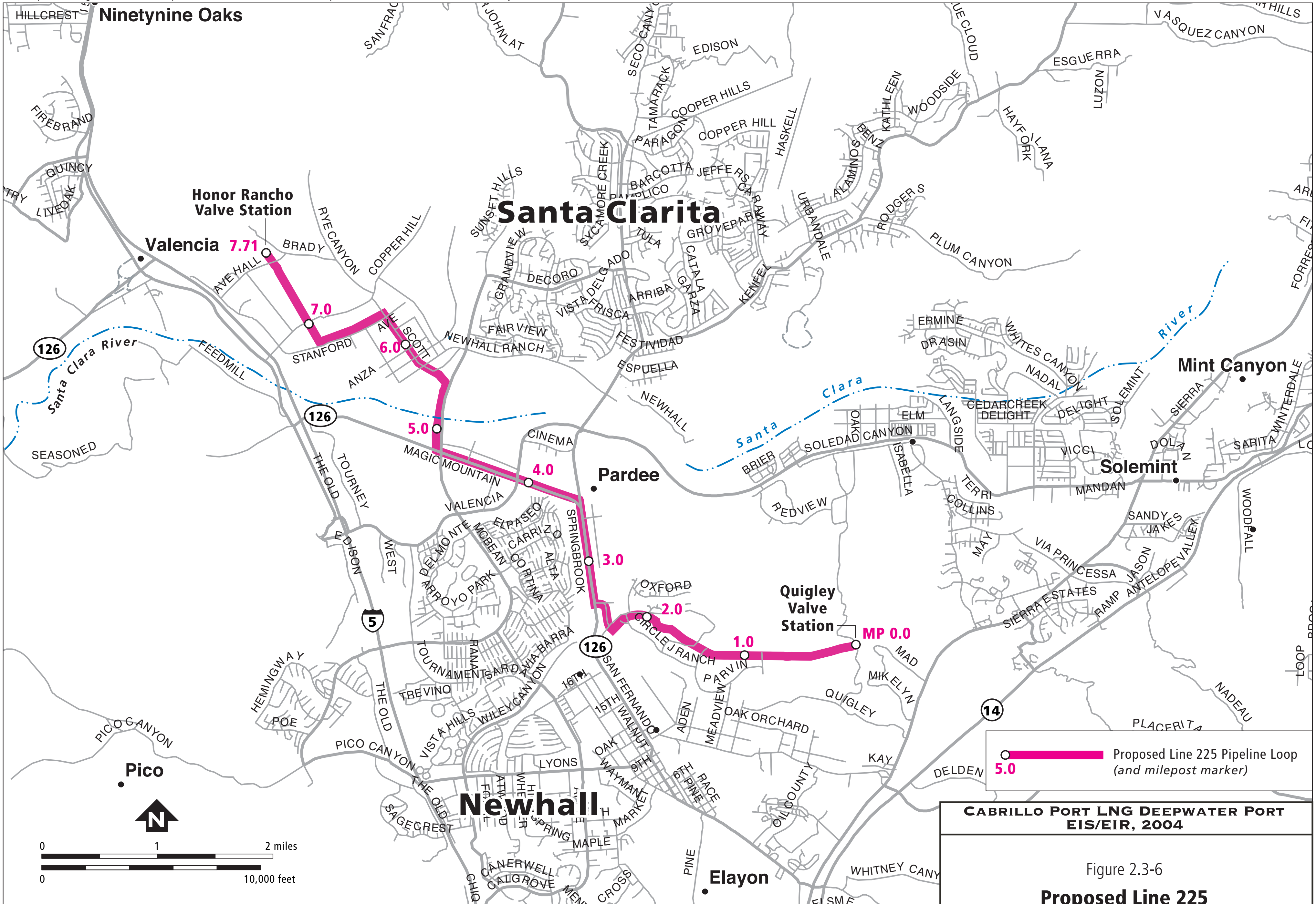

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Figure 2.3-6

Proposed Line 225 Pipeline Loop Location

The final alignment of the pipeline within the proposed ROWs would be determined by detailed engineering design and analysis; until that alignment is known, the precise land ownership and location within public or private ROWs would not be known. Permanent easements and temporary construction easements would be required outside of private and, in most cases, public road ROWs. Permanent easements would range between 25 and 50 feet (7.6 and 15.2 m) depending on site-specific conditions.

Ormond Beach Metering Station

This facility would be located within the existing Reliant Energy Ormond Beach Generating Station shore crossing. The facility would consist of 3.5-foot (1.1 m) tall aboveground valve actuators; 8-foot (2.4 m) blowdown stacks; a small instrument building (8 to 9 feet [2.4 to 2.7 m] tall); pig launchers and receivers; a gas odorant injection station; and a concrete pad. Pigs are devices that are used to clean, inspect, and maintain pipelines; pigs also measure the wall thickness of the pipe, corrosion, and other pipeline anomalies. Depending on the final design, the odorizing equipment would consist of a 10,000-gallon (37.9 m^3) aboveground, pressurized storage vessel containing odorant, which would require refilling approximately two to three times per year, a concrete containment pad, and a pump. Alternatively, the facility could use a 5,000 to 6,000-gallon (18.9 to 22.7 m^3) storage tank that would require refilling about four times per year. (For more information on the odorant, see Section 2.5.4, "Onshore Pipelines and Aboveground Facilities.") A curb designed to contain 110 percent of the volume of the tank would surround the concrete pad.

Center Road Valve Station Expansion

This expansion of this facility would include pressure reduction/regulation facilities, multistage pressure drop/gas warming, and gas quality monitoring equipment. In addition, blowdown- and pig-receiving facilities would be installed. Electrical and communications equipment would also be installed. The facilities would not be lit at night.

Main Line Block Valves

Two main line block valves would be installed along the Center Road Pipeline route along Pleasant Valley Road and Central Avenue, respectively. They would likely be located out of the roadway in agricultural fields. They would be permanently installed within a fenced area with above-grade valve actuators 3 feet (0.9 m) tall, an 8-foot (2.4 m) blowdown stack, a small 8- to 9-foot (2.4 to 2.7 m) tall instrument building, a concrete pad, and a pig launcher. The valve bodies would be buried. If the locations were in the paved road, the installations would be in two buried concrete vaults, one for the main block valves and the other for the blowdown assemblies. The facilities would not be lit at night.

2.3.4.2 Line 225 Pipeline Loop

The proposed Line 225 Pipeline Loop would have a 30-inch (0.76 m) diameter, be designed for an MAOP of 756 psi (531,500 kg/m^2), and extend approximately 7.7 miles

(12.4 km) between Quigley Valve Station and the Honor Rancho Storage Facility. The proposed new loop pipeline in Santa Clarita, Los Angeles County would generally parallel the existing Line 225 Pipeline either in or near the existing ROWs within unpaved parts of the route. Along city and county roadways, the pipeline would parallel the existing Line 225 Pipeline to the extent practical. The proposed new pipeline route is as follows:

- From the Quigley Valve Station, the pipeline would parallel the existing Line 225 Pipeline in a westerly direction to Via Princessa, then proceed west on Via Princessa to Oak Ridge. The pipeline would proceed north within Oak Ridge, then north within San Fernando Road to Magic Mountain Parkway.
- The pipeline would then proceed in a northwesterly direction within Magic Mountain Parkway to McBean Parkway, where it would proceed north to Scott Avenue and then northwest to Stanford Avenue.
- Then the pipeline would parallel the existing Line 225 Pipeline ROW and would cross the South Fork Santa Clara River, the Santa Clara River, and San Francisquito Creek.
- The pipeline would then proceed northwest for approximately 1 mile (1.6 km) to the Honor Rancho Valve Station and Storage Facility through an existing utility ROW containing four pipelines and seven overhead power lines.

The alignment would cross the South Fork Santa Clara River at Magic Mountain Parkway, the Santa Clara River at McBean Parkway, and the San Francisquito Creek at McBean Parkway. Only the South Fork Santa Clara River crossing is a closed girder bridge; the remaining two are open girder bridges. The road bridges would not require significant improvements to accommodate the pipeline.

Quigley Valve Station Expansion

This expansion would include pressure reduction/regulation facilities, multistage pressure drop/gas warming, and gas quality monitoring equipment for the proposed new Line 225 Pipeline Loop. In addition, blowdown and pig-receiving facilities would be installed. Electrical and communications equipment would also be installed. The facilities would not be lit at night.

Honor Rancho Valve Station

Modification of the valve station could be required for the proposed new Line 225 Pipeline Loop, including new control valves and other equipment to be determined. This equipment would be placed within the existing facility footprint. The facilities would not be lit at night.

2.4 CONSTRUCTION AND INSTALLATION

The previous section described the proposed Project facilities. Section 2.4 discusses how the facilities would be constructed and installed. Section 2.5 discusses how the facilities would be operated and maintained.

2.4.1 Floating Storage and Regasification Unit and Mooring System

2.4.1.1 Floating Storage and Regasification Unit

Potential fabrication yards for the FSRU are in Japan, Korea, Spain, and Finland. All fabrication activities would adhere to the fabricator's own ISO 9000 type of quality assurance program. The USCG would require a quality management plan, the implementation of which would be independently checked by a verification agent such as a classification society on behalf of the USCG in consultation with the CSLC, as would all offshore installation activities (including mooring pre-tensioning, hydrotesting, etc.). The FSRU would be towed from its fabrication point by two ocean-going tugs in accordance with a towing plan. This plan would be developed by the Applicant and submitted to the USCG and CSLC for approval before installation of the FSRU would occur (as discussed in Section 4.3 “Marine Traffic”).

Two anchor-handling tug supply vessels would tow the FSRU from the fabrication site to the mooring location in Federal waters. Two barges would transport anchors and equipment to the mooring location, and two supply vessels (at 4,500 horsepower [Hp] each) would transport materials and crew.

Before initial arrival of the FSRU from the overseas fabrication port, the FSRU would follow established ballast water exchange protocol in accordance with the International Convention of the Prevention of Pollution from Ships (MARPOL) and State of California and USCG requirements, including notification and exchange of ballast water outside the 200 NM (230 miles or 371 km) Exclusive Economic Zone limit.

2.4.1.2 Mooring System

Before mooring installation, additional site-specific surveys and testing would be performed to supplement the geophysical and geotechnical testing program already conducted by the Applicant and independently reviewed by the EIS/EIR Project team. The results of the additional testing, which would include a determination of the allowable anchor pull, would be used to coordinate layout positions of the anchor leg components. The geophysical and geotechnical work would be performed under the supervision of a California Registered Geologist or a California Registered Civil Engineer.

Mooring installation would occur over a 45-day period on a 24-hour per day basis. (Tie in to the mooring point is anticipated to require approximately 24 days, using 12-hour workdays.) On nine of these days, nine conventional drag-embedded anchors would be placed on the seabed and embedded with the mooring lines attached. Anchors would be positioned within the design limits as required.

The FSRU would arrive at the site with the mooring turret and anchor-pulling equipment pre-installed. Two tugs would hold the FSRU in place, and a third tug would be used to retrieve and hook up the nine mooring legs to the FSRU turret. Hook-up vessels would retrieve the end of each anchor leg, pass it over to the FSRU turret, which would pull in each anchor line and make the final connection between the FSRU and the anchor leg. After all legs were connected, final adjustments would be made until the correct tension was present in each anchor leg. All risers and connecting cables would then be similarly retrieved from the seabed and passed over to the FSRU for final connection to the FSRU turret.

A full hydrostatic test would then be conducted to check the pressure integrity of product swivels, piping, and valves. All testing and checking would be subject to classification society independent third-party verification.

All equipment provided on the turret, including lube systems, leak detection systems, and electrical and hydraulic systems, would be function-tested by the Applicant and its contractors with the independent third-party verification of a classification society.

2.4.2 Offshore Pipelines and Associated Facilities

The two subsea pipelines would be laid between individual offshore target boxes at a depth of 2,850 feet (869 m) near the PLEM and target boxes at an approximate depth of 42.7 feet (13 m) near the HDD offshore pipeline. The target boxes are radio transmitters placed at predetermined locations using a global positioning system (GPS). Each pipeline would tie in to a HDD pipeline and would run to the Reliant Energy Ormond Beach Generating Station shore crossing. Pipeline installation would occur over 45 days or less. The offshore pipeline installation would employ up to 200 non-local workers, who would be housed on the pipe-laying barge during construction activities.

As shown on Figure 2.4-1, the HDDs would be drilled from the beach, with an offshore spud barge supporting the construction operations. The pipe for the HDDs would be laid on the seafloor so that it could be pulled from the beach through the pre-drilled holes. Onshore traffic would not be affected by HDD operations.

The offshore pipeline installation would consist of the following steps: (1) a pre-lay survey that would be compared with the previous bottom hazard surveys conducted by the Applicant; (2) offshore pipeline preparation, welding, and testing; (3) transport of materials to the site; (4) pipe-laying; (5) post-lay testing; and (6) other ROW crossings.

2.4.2.1 Pre-Lay Survey

A pre-lay hazard survey would be completed and compared with previous bottom hazard surveys before construction would begin. A pipeline lay corridor would be established and programmed into the pipe-laying vessel's navigation system. A chase boat (a boat that follows a lay vessel) equipped with an ROV would monitor the pipeline contact with the ocean floor. The pipe-laying vessel would use a differential global positioning system (DGPS) that receives satellite communications to accurately position

Source: BHP Billiton

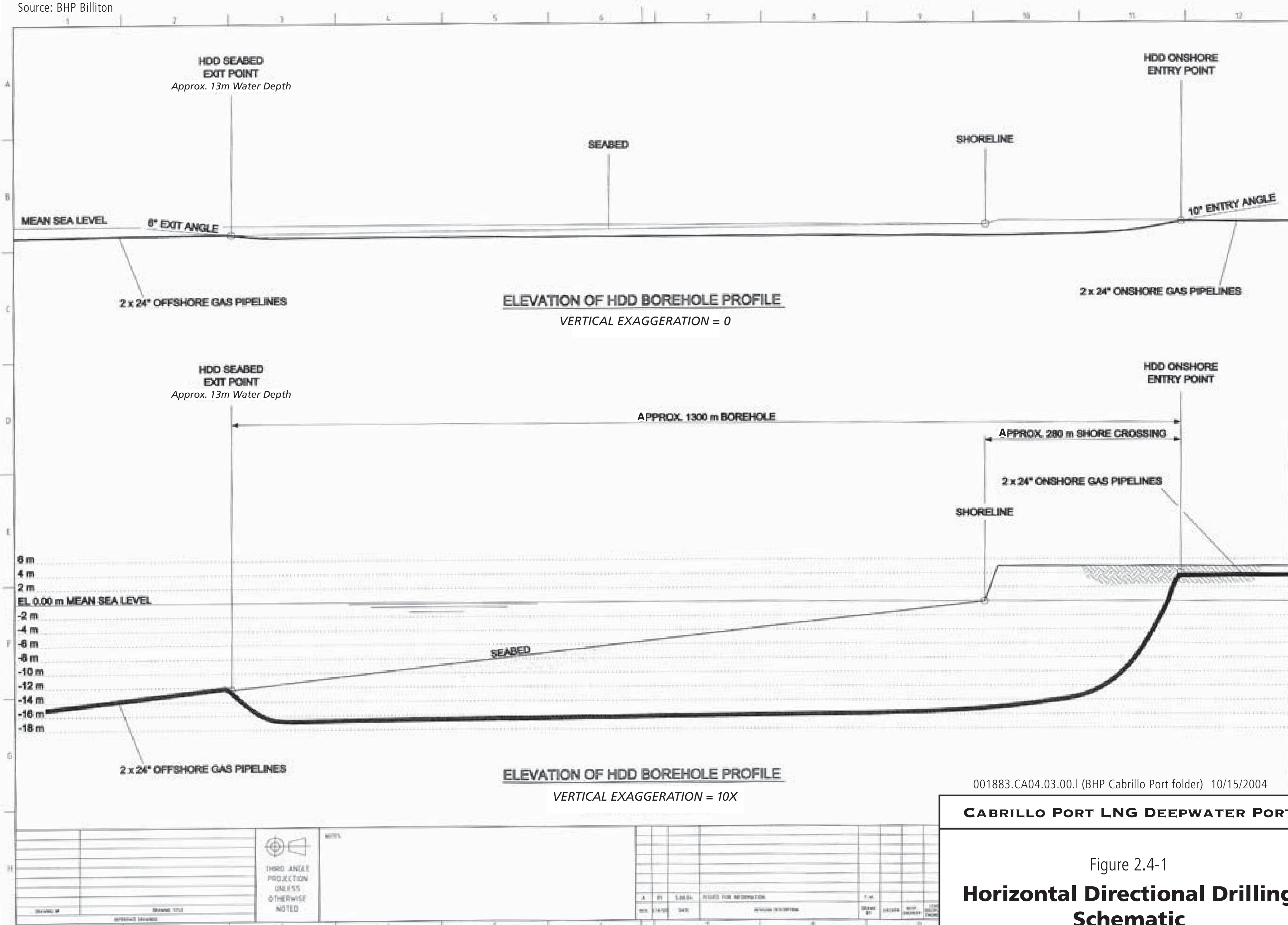

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Figure 2.4-1

Horizontal Directional Drilling Schematic

itself over the seafloor. The offshore pipelines would be installed 50 feet (15 m) to each side of the centerline of the route.

The offshore ROW would be prepared for construction before the arrival of the pipe-laying equipment. Preparation activities would occur at the cable crossings and the exit hole location of the HDD. All other activities would occur on the pipe-laying vessels. A "sleeper," or bridge, would be placed over the cables on which the pipelines would be placed.

Preparation of the HDD exit hole locations would involve excavating an area and installing a temporary sheet pile fluid containment cofferdam for the drilling mud. The onshore HDD entry locations would require a cofferdam to contain drilling mud and a staging area to stage the drill rig and drill pipe. Laboratory analyses of sediments in the area have confirmed that the sediments are not contaminated. (See Section 4.18, "Water Quality and Sediments" for discussion of potential impacts from drilling mud.)

2.4.2.2 Offshore Pipeline Preparation, Welding, and Testing

The twin pipelines would be made of carbon steel and coated with an anti-corrosion coating. In addition, sections of the pipeline would be concrete-coated to prevent waves from moving the pipeline (in areas where necessary, based on information submitted by the Applicant and EIS/EIR analyses). Aluminum anode rings (called "bracelets") would be attached at regular spacing along the pipeline to provide cathodic corrosion protection. Finally, in areas where necessary, based on local conditions, stiffening ring elements (called "Buckle arrestors") would be attached to the pipeline at regular spacings to prevent the pipeline from collapsing under hydrostatic water pressure. During pipe fabrication on the pipe-laying vessel, the ends of the pipe joints would be cleaned and aligned, and the welding passes would be made. The field joint would then pass through a non-destructive examination station, where the contractor's and a third party's welding inspectors would examine the completed weld to verify its quality. If the weld contained an unacceptable defect, the defect would be removed, and the weld would be repaired and re-examined. All welds would be inspected.

After the non-destructive equipment examination, the field joint would be coated with an anti-corrosion coating system compatible with that applied onshore. The coating of all field welds would be visually inspected and examined with an electronic device to detect coating defects. All coating defects would be repaired before the pipe enters the water. All welding and coating would be completed in accordance with 49 CFR 192 and the current edition of American Petroleum Institute (API) Standard 1104. Inspection acceptance would be in accordance with American Welding Society (AWS) requirements.

2.4.2.3 Transport of Materials to the Site

The pipe-laying vessel would mobilize with essential equipment (from a currently unknown pipe supplier). Supply vessels would mobilize all additional and necessary equipment, materials, and personnel. Before shipment of the pipes to the pipe-laying vessel, all pipe joints would be checked. The pipes would be loaded in a nearby port (e.g., Port Hueneme) on no more than four cargo barges for transport to the pipe-laying vessel. The exact number of trips would depend on the size of the barges, the port of origin, and the level of safe loading for the barges. Pipes that were transported to the lay vessel would already have a fusion-bonded epoxy and concrete coating, as required. During unloading of pipes from the cargo barge, a visual inspection would be conducted to detect any damage to line pipe during transit. Pipe joints failing to meet the requirements of the visual inspections would be marked for immediate repair or rejection.

2.4.2.4 Pipeline Laying

Equipment and vessels that would be used during pipe laying are summarized in Table 2.4-1 below:

Table 2.4-1 Pipeline Construction Vessels and Equipment, Use, and Duration of Use

Vessel/Equipment	Use	Duration
4 Pipe-laying Barges (unpowered)	Transport Pipe and Materials Offshore	35 days – 24 hours per day
2 Mooring Support Barges (unpowered)	Transport Anchors and Related Equipment Offshore for the FSRU	20 days – 12 hours per day
1 Work Boat	Riser Installation Vessel	10 days – 12 hours per day
1 Dynamically Positioned Pipe-Laying Vessel (DPV)	Barge positioning	35 days – 24 hours per day
2 Tug Supply Vessels	Logistical support	20 days - 12 hours per day
1 Diesel-Powered Crane (100-ton capacity)	Pipe handling and loading	25 days – 12 hours per day
1 Diesel-Powered Crane (35-ton capacity)	Pipe handling and loading	25 days – 12 hours per day
1 Supply Boat	Transport of supplies offshore	25 days – 24 hours per day

Pipeline construction would require the use of one deepwater pipe-lay spread, which includes all of the vessels and crew required to lay both subsea pipelines. The dynamically positioned pipe-laying vessel (DPV) would operate at an average 35 percent loading, using ten diesel welding units and two tug supply vessels, which would provide logistical support on a 24-hour basis for 35 days. Using DPV would eliminate the need to place anchors along the route during pipe-laying operations. The tugs would also supply welding power as needed. Construction equipment would also include one 100-ton (101,600 kg) capacity diesel crane and one 35-ton (35,560 kg) capacity diesel crane working 8-hour days and four pipe barges, needed to transport pipe and material offshore.

The DPV would start at the offshore entry points of the HDD. The DPV would align itself with the pipelines and the laydown heads would be pulled onboard the pipe-laying vessel. The next pipeline line joints would be lined up with the HDD pipe string and then the welding process would occur. Following welding, inspection, and coating, the pipe-laying barge would move ahead the length of that one joint to repeat the process. A curved metal lattice tail called a ‘stinger’ would extend beyond the edge of the vessel and be used to lay the pipe on the seabed without causing any kinks or buckles. An ROV would be used to monitor the touchdown of pipe on the ocean floor.

The installation contractor would perform engineering calculations to ensure that pipeline stress during installation would not exceed industry-accepted limits. Pipeline stress during installation would be controlled through adjustment and control of the laying tension.

2.4.2.5 Post-Lay Testing

The offshore pipeline segments would be tested in accordance with Department of Transportation (DOT) regulations contained in 49 CFR Part 192. The number and locations of test sections would depend on pipeline class location, elevation differences along the route, and construction constraints. (See Section 4.2.6.2 for discussion of “class locations.”)

Before hydrostatic testing, a sizing plate would be installed on a pig and pushed through the pipelines to verify that the pipelines did not sustain any damage during installation. Approximately 2.5 million gallons (9,500 m^3) of test water would be drawn from appropriate and approved sources, likely derived from the City of Oxnard municipal supply. The water would be sent from shore through one of the two 24-inch (0.6 m) pipelines to the FSRU and returned to shore for disposal through the other 24-inch (0.6 m) pipeline. After completing the testing, the water in the pipelines would be discharged onshore using two or more dewatering pigs. The discharged water would meet water quality standards for hydrostatic test water.

The Applicant would not chemically treat the hydrostatic test water from sections of the pipelines where the residence time of the water in the pipelines was less than 10 to 14 days. If a longer residence time were required, oxygen scavengers and biocides would be added to limit corrosion. Oxygen scavengers would be removed by aeration during discharge. The percentage of biocide would be kept sufficiently small and the residence time in the pipelines kept sufficiently long to render the biocide no longer harmful upon discharge. The actual residence time would be chemical-specific.

2.4.2.6 Other Right-of-Way Crossings

The proposed subsea transmission pipelines would not cross any known Federal or State oil and gas leases, pipelines, or pipeline ROWs, but would cross three fiber optic cables.

All cable crossings are located outside of State waters. The cable owners have been notified of the proposed pipeline routing, and their approval of cable crossings has been requested. Crossings of existing cables would be protected by installing sandbags, concrete mats, and/or "sleepers,” which are fabricated steel pipe supports designed to hold the pipeline off the sea floor while protecting against sagging and abrasion of the pipe walls.

2.4.3 Shore Crossing

As previously indicated, two HDD borings would be drilled and trenching would be employed to install the 0.65-mile (1.05 km) shore connection. Approximately 0.3 mile (500 m) of the 0.65-mile (1.04 km) shore crossing would be constructed using HDD for each pipeline. The remaining 0.35 miles (0.56 km) of the shore crossing would be constructed using standard pipeline trenching techniques. Completion of HDD operations is projected to require 60 days at 24 hours per day.

Before starting the HDD, survey crews would identify and flag buried utilities at the work site; confirm water depths; and determine and mark the exit and entry points. At the onshore entry point, a drilling fluids containment pit would be excavated. This pit would be approximately 10 feet wide by 10 feet long by 2 to 3 feet deep (3 m wide by 3 m long by 0.6 to 0.9 m deep). The depth of the pipeline would be at least 35 feet (10.7 m) below the sea floor. A geotechnical investigation would be conducted to determine the suitable depth/profile of the pipeline to be installed by the HDD.

Equipment would include a mud mixing/cleaning tank, one onshore and one offshore drilling rig, mud pump, open-topped liquid storage tanks, a backhoe, a forklift, six light towers for night work, a tug for the exit hole barge, a supply boat that would also be used for welding power, four pipe barges to transport pipe and materials offshore, and fuel tanks, which would conform to state and local requirements. Before excavation, one or more temporary fluid containment cofferdams made of sheet pile would be installed at the offshore exit point to protect the operation from currents and waves and to prevent releases of drilling mud to the marine environment.

The HDD rig would drill from the entry hole seaward. Upon punching-out at the exit point cofferdam, air would be pumped from the drilling rig through the pilot pipe to locate the actual punch-out position offshore. Divers would locate the exit point and attach a wire sling to the end of the drill pipe. The borehole would be reamed, to increase the diameter, and stabilized using drilling mud.

It is anticipated that the HDD would be drilled from the landward entrance point at the Reliant Energy Ormond Beach Generating Station shore crossing to the offshore pipe-stringing site. After the onshore drill rig drills the holes for the pipelines, the pipe would be laid on the seafloor and then pulled landward through the pre-drilled holes. The pulling operation would be continuous to minimize the chance of hole collapse.

Trenching would be employed for a 0.35-mile (0.56 km) segment to install the pipelines from the HDD exit at Ormond Beach to the SoCalGas tie-in location at the Reliant Energy Ormond Beach Generating Station shore crossing. The trenches would be on previously disturbed, unvegetated land formerly used for industrial purposes.

The anticipated construction work force for HDD is approximately 45 workers, consisting of approximately 15 percent local hires and 85 percent non-local workers.

2.4.4 Onshore Pipelines and Associated Facilities

Onshore pipeline construction is expected to begin in the third quarter of 2007 and to require approximately eight months to complete. Onshore pipeline construction would typically proceed at 300 to 500 feet (91.4 to 152.4 m) per day. Both the pipeline from shore to Center Road station and the pipeline in Santa Clarita would be constructed concurrently. Onshore pipeline construction would occur six days per week (Monday through Saturday), from 7 a.m. to 7 p.m., although the City of Santa Clarita Planning Office has indicated that the westernmost portion of the proposed new Line 225 Loop may need to be constructed at night in areas where the Loop is located in an industrial zone (Follstad August 2004). Biological and cultural resource monitors and other compliance monitors would be on-site at times during construction, as required by regulatory agencies. A construction workforce of approximately 100 to 120 personnel for each pipeline would be employed on the Project during the peak construction period. Most, if not all, of these workers would come from the three counties surrounding the Project site.

During construction, temporary construction easements and workspaces would be established as summarized in Tables 2.2-2 and 2.2-3 and described in the following subsections.

Construction of the pipeline within the existing paved roads would require temporary closure of at least one or two lanes in accordance with a traffic control plan, which would be submitted by SoCalGas and approved by the responsible jurisdiction (affected county or municipality). Appropriate warning signs would be placed at strategic locations to warn drivers of the closed lanes. Flagmen could be used at busy intersections or roadways. Construction of temporary access roads and work strips would be required along unpaved roads in agricultural areas. Conventional boring techniques may be employed to install the pipeline beneath highways and railroads. Potential impacts are discussed in Section 4.17, "Transportation."

Onshore pipeline construction would be conducted using one or two main construction "spreads" (workers and equipment) for each onshore pipeline. As shown on Figure 2.4-2, construction would proceed in the following general order: (1) pre-construction activities, including surveying and staking and ROW or pavement cutting; (2) ditching; (3) hauling, stringing, and bending the line pipe; (4) lowering in, line-up, and welding; (5) weld inspection; (6) application of protective coating to weld joints; (7) backfilling; (8) hydrostatic testing; and (9) ROW cleanup, paving, and restoration.

2.4.4.1 Pre-Construction Activities

Epoxy pipeline coating would be applied at the pipe mill before delivery to the construction site. Field coating would be necessary on all field weld joints made at the site to provide a continuous coating along the pipeline. After the pipe is welded and radiographically inspected (X-rayed), fusion-bonded epoxy or two-part epoxy would be used to coat the weld.

SoCalGas personnel would conduct tests along the pipe, field joints, fittings, and bends to locate any coating discontinuities such as thinning or other mechanical damage that could allow moisture to reach the pipe. Repairs would be made as necessary before lowering the pipe into the ditch. Onshore pipeline construction work would begin with a ROW survey, property owner notifications, and a one-call notification to identify utilities, road crossings, and other uses that may be impacted by the construction. The construction ROW and extra workspaces necessary for boring beneath highways and railroads and the ROW required for trenching would be cleared to remove obstructions. Fences would be cut and braced as necessary.

2.4.4.2 Ditching

After clearing an area, a 4.5-foot (1.4 m) wide, 7-foot- (2.1 m) deep ditch would be excavated with a backhoe or trencher. The depth could vary if special conditions were encountered, e.g., crossing existing substructures. Previously identified buried utilities such as other pipelines, cables, water mains, and sewers would be located by hand digging. Blasting is not anticipated. If groundwater is encountered, temporary dewatering could be required. Water discharges would be in accordance with the National Pollutant Discharge Elimination System (NPDES) permit for the Project.

2.4.4.3 Hauling, Stringing, and Bending

After a spread is ditched, pipe-stringing trucks would transport the pipe in 40-foot to 80-foot (12.2 m to 24.4 m) lengths to the pipeline ROW. Where sufficient space exists, trucks would carry the pipe along the ROW. Sideboom tractors would unload the pipe joints and lay them end-to-end beside the ditch line for future line-up and welding.

The pipe would be bent in the field, vertically and horizontally, to fit the contour of the ditch. Construction in roadways with existing substructures would require pipe bends for which bending in the field would not be practical. In these cases, manufactured or shop-made bends would be used.

Following the line-up crew, the welding crew would apply the remaining weld passes to complete the weld. SoCalGas personnel would conduct a 100 percent visual and radiographic inspection of all pipeline welds. Fugitive dust emissions during earth-moving operations would be controlled using water trucks equipped with fine-spray nozzles. Approximately 30,000 gallons (114 m^3) of water would be used per day for dust suppression. The most likely source would be municipal water purchased from the City of Oxnard municipal water supply or other similar source.

2.4.4.4 Lowering In, Line-up, and Welding

After laying the pipe next to the ditch for one spread, the pipe would be lowered into the ditch by sideboom tractors, which would be spaced so that the weight of unsupported pipe would not cause mechanical damage. Ditch welds would be required and would be made at the final elevation. Each weld would require pipe handling for line-up, coating, and backfilling, in addition to normal welding and weld inspection.

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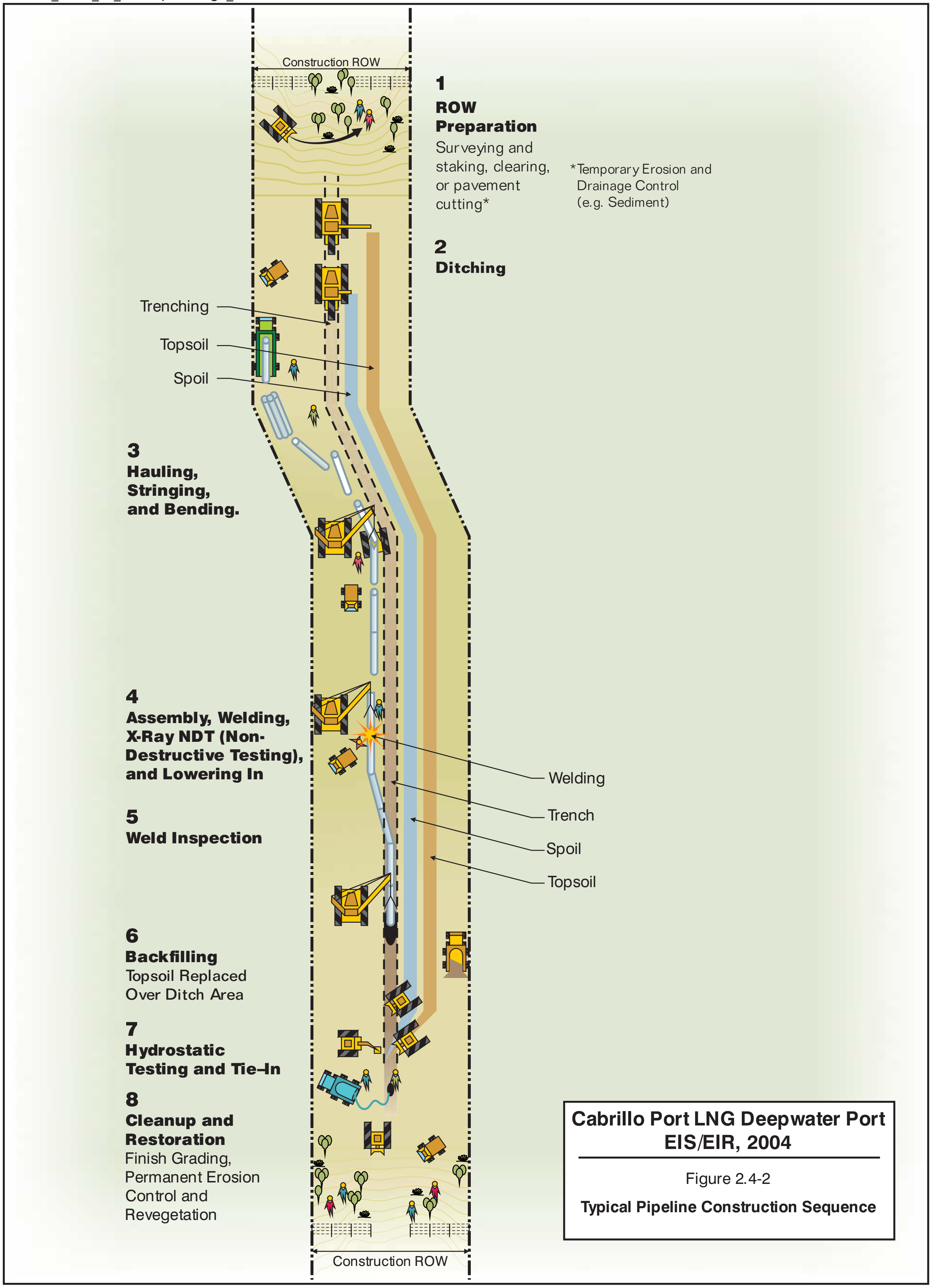

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Figure 2.4-2

Typical Pipeline Construction Sequence

Welders certified and tested to meet SoCalGas procedures would perform all field welding. Welding would comply with the specifications of all applicable State and Federal regulations, including DOT 49 CFR 192 (for natural gas pipelines) and CPUC regulations regarding gas pipelines, General Order 112E.

All welds would be 100 percent radiographically inspected. Radiographs would be recorded and interpreted for acceptability according to applicable regulatory requirements. All rejected welds would be repaired or replaced as necessary and re-radiographed. SoCalGas would retain the X-ray reports and a record indicating the locations of welds.

2.4.4.5 Backfilling

Soils removed during excavation would be segregated to separate topsoil from subsoil, which would subsequently be used to backfill the trench following pipeline placement and inspection. Spoils would generally be returned to the ditch within one week of trenching. The spoils would be screened using standard construction screening equipment, as required. The pipe would be covered along the sides with a maximum of 6 inches (15.2 centimeters [cm]) of native fill free of rocks, then covered on top with at least 12 inches (30.5 cm) of backfill free of rocks. In certain areas where the pipe coating might be damaged by abrasive soils along the bottom of the trench, clean sand or earthen backfill would be used to pad the pipeline. The backfill in the remainder of the trench above the padding would be native material excavated during trenching. The segregated topsoil would be used to cap the trench.

During backfilling, a colored warning tape would be buried approximately 18 inches (45.7 cm) above the pipeline to indicate the presence of a buried pipeline to future third-party excavators. Backfilled soil would be compacted using a sheepsfoot compactor, vibratory roller, or hydraulic tamper before paving. Compaction density and compaction testing would be performed in accordance with the affected municipalities' requirements.

2.4.4.6 Hydrostatic Testing

The installed onshore pipelines would be hydrostatically tested after construction and before startup pursuant to Federal regulations (49 CFR 192). Such tests are designed to ensure that pipe, fittings, and weld sections maintain structural integrity without failure or leakage under pressure. The test section of the pipeline would be filled with water and the pressure would be increased to at least one and one-half times the pipeline maximum operating pressure. The test period would be in accordance with CPUC guidelines. An estimated 3.25 million gallons (12,300 m^3) of water would be used in testing for both onshore pipelines. Water would be obtained from a potable water source along the route. Hydrostatic test water would be discharged to an existing channel or wash along the route pursuant to a NPDES permit.

Before discharge, the hydrostatic test water would be evaluated to ensure that it meets local, State, or Federal water quality standards. SoCalGas also would design and install a suitable energy dissipater at the outlets and design and install suitable channel protection structures to ensure that there would be no erosion or scouring of natural channels within the affected watershed. These structures would be removed from the site upon completion of hydrostatic testing.

SoCalGas would keep permanent records of each hydrostatic test for the life of the pipeline. These records would be accessible to the responsible regulatory agencies and would contain the exact location of the test segment, the elevation profile, a description of the facility, and continuous pressure and temperature readings of the line throughout the test.

2.4.4.7 Right-of-Way Cleanup, Paving, and Restoration

After completing the pipeline construction, cleanup, paving, and restoration would occur. Restoration would entail repairing the trench cut within the roadway by paving; re-contouring the dirt ROW; and removing debris, construction signs, surplus material, and equipment from construction areas. Erosion and drainage control measures such as water bars, drainage ditches, culverts, silt fences, and energy dissipaters would be installed where necessary to control erosion. Revegetation and re-seeding within dirt parts of the ROW would be performed where required.

2.4.5 Crossing Techniques

During installation of the onshore pipelines both watercourses and roads would be crossed.

Watercourse Crossing

Water crossings would occur at the Santa Clara River, the South Fork Santa Clara River, and San Francisquito Creek. The pipeline would cross Santa Clara River at McBean Parkway and San Francisquito Creek at Avenue Scott by hanging it underneath the open girder bridges. The pipeline across the South Fork Santa Clara River at Magic Mountain Parkway would be installed inside a closed girder bridge. Other crossings such as at several concrete-lined flood control channels may require using existing road bridges or HDD. Each crossing would need to be evaluated by SoCalGas construction engineers and alternative crossing methods developed.

To avoid or reduce impacts to aquatic resources, all dry watercourse or minor wet crossings would be open-cut-trenched. The open-cut technique would require a trench to be excavated from bank to bank. Equipment such as backhoes, bulldozers, and draglines would be used to excavate the ditch. The pipe would be placed below the scour depth of the wash channel with an adequate margin of safety to ensure that the pipe is not exposed by wash bed scour. The wash channel would be returned to its original configuration, the substrate would be replaced, and the banks would be stabilized and revegetated as necessary. A U.S. Army Corps of Engineers (USACE) Clean Water Act Section 404 Nationwide Permit No. 12 (Utility Line Discharges) and a California Department of Fish and Game (CDFG) Streambed Alteration Agreement

(Fish and Game Code Section 1602) would be obtained for watercourse crossings as required. SoCalGas would obtain all permits.

Road Crossings

The proposed pipelines would cross several primary roadways as well as U.S. Highway 1 and U.S. Highway 101. Most road crossings would be excavated. Before construction, all utilities would be identified and marked. Once traffic control measures were in place, a 7-foot (2.1 m) deep ditch would be excavated; previously identified buried utilities would be located first by manual digging and would be measured to determine the trench depth required to clear them. Road crossings would be completed in accordance with the municipalities' requirements. Where excavating across roadways or highways is not practical, such as areas with very wide roadways, roadways with heavy traffic loads, or where permission of landowner could not be obtained, the pipeline would be constructed by conventional boring with a permanent casing.

Conventional boring under U.S. Highway 101 and U.S. Highway 1 would require bore pits on each side of the highway. The pits would be approximately 15 to 30 feet (4.6 to 9.1 m) long and 8 feet (2.4 m) wide. The depth of the pits would depend on the final pipeline depth. Excavation spoils would be placed alongside the pits and would be used as backfill. Casing and pipe sections would be welded, inspected, and coated in the pit before boring. Upon completion of the pipeline installation, the excavated areas would be backfilled, compacted, and restored to natural contours.

2.4.6 Off-Right-of-Way Activities

2.4.6.1 Staging and Storage Areas

There would be three staging areas for the Center Road Pipeline and two staging areas for the Line 225 Pipeline Loop. The staging areas would hold equipment, excess spoils, and contractor offices and materials and would serve for parking for construction workers. Each staging area would be located as close as practical to the construction route. Existing roads would be used for all construction-related traffic and equipment mobilization; no new permanent access roads would be needed. Where the routes traverse unpaved areas, temporary access roads and work strips, typically 75 feet (22.9 m) wide, would be required. Staging or lay-down areas would be located on private property on previously disturbed land. During all phases of construction, refueling and lubrication of construction equipment would occur in the contractor's staging areas.

No new pipe yards would be required for the onshore Project. The pipe yards to be used are owned by SoCalGas or other entities. The exact locations have not been determined but would likely be in the Fontana and San Bernardino areas.

2.4.6.2 Transportation

Most heavy construction equipment would be delivered to the initial point of the spread on lowboy trucks or trailers. Mobile cranes and dump trucks would be driven to the construction site from existing local contractor yards. Construction equipment would be left overnight either at the site, at contractor yards, or at other existing storage yards in the area. All construction materials would be transported to the construction spreads by truck on existing roadways. An estimated 400 to 450 truck trips would be required to deliver materials and equipment for the Project. All vehicles would be regulation-sized except for pipe-laying equipment, which could require oversized loads. The vehicles would include one-ton flatbed trucks, lowboys, pipe dollies, and dump trucks. The contractor would be responsible for local hauling permits with appropriate agencies.

2.5 OPERATION AND MAINTENANCE

2.5.1 Floating Storage and Regasification Unit and Mooring System

This section describes how the FSRU would be serviced. Other aspects of FSRU operation are described in Section 2.3, "Description of the Proposed Facilities." The FSRU and offshore pipelines would comply with an operations plan that would be approved by the USCG in consultation with the CSLC.

Material and Personnel Transfers

The FSRU would receive LNG shipments two to three times per week on average, weather permitting, given standard operating procedure restrictions of wave heights of 9.2 feet (2.8 m).

Incoming supplies and outgoing wastes would be transferred by supply boat. Solid supplies could include food, toiletries, office supplies, tools, spare parts, dry chemicals, and other maintenance and repair materials. Wastes from the FSRU that could not be discharged pursuant to the facility-specific NPDES permit issued by the USEPA would be containerized for transfer to the supply vessel. It is estimated that the supply vessel would visit the FSRU once per week, resulting in 52 round-trip transits per year.

The normal operations crew of about 30 persons would be rotated every seven days and transferred by boat, resulting in two transits per week, or 52 round-trip transits per year.

LNG carrier wastes would not be transferred to the FSRU, nor would the FSRU replenish supplies for the LNG carrier. The LNG carriers would be re-supplied and provided with logistical support by supply boats that would attend the LNG carrier while it is moored to the FSRU.

2.5.1.2 Emissions and Water Discharges

Cold Stack

The plant would be equipped with a "cold stack," which would allow gas to be vented to the atmosphere. Venting would be allowed only in case of an emergency or abnormal process to vent the free gas in the plant piping or, in some incidents, to vent the volume of gas in the subsea pipeline. The amount of gas that would be vented during an emergency situation would depend on the severity of the situation. Under normal circumstances, no gas would be vented to the atmosphere. There would never be any flaring. The cold stack is preferred over flaring as it eliminates an ignition source aboard the FSRU. The vented gas would not be considered an asphyxiant for the FSRU crew because (a) the gas is lighter than air and would therefore rise, and (b) the top of the cold stack would be the highest point on the vessel, well above the decks.

Submerged Combustion Vaporizer Water Discharge

The combustion process in the submerged combustion vaporizer units would continuously generate fresh water as a by-product. Each submerged combustion vaporizer would produce approximately 39,936 gallons (151 m^3) per day. With an average of five submerged combustion vaporizers operating simultaneously, the total discharge would be approximately 199,680 gallons (756 m^3) per day. This water would accumulate in the combustion vaporizer water bath and eventually would have to be discharged. This excess water bath, consisting of clean, distilled water, would be treated (i.e., the pH would be adjusted) and used onboard the FSRU for potable water and facility washdown. Any excess water from the vaporizer units would be discharged overboard pursuant to an NPDES permit issued by the USEPA.

Generator Engine Cooling Water

The four generator engines would use a closed circuit cooling water system with a charge capacity of 396 gallons (1.5 m^3) per engine. Each engine would have two cooling circuits. A small amount, approximately 10 percent, of make-up water would be required per year. Therefore, fresh water consumption would total about 300 gallons (1.2 m^3) annually. The anti-fouling inhibitors would be a generic glycol-based product as specified by vendor specifications. The closed circuit cooling water system would employ non-contact seawater for heat transfer in an amount estimated at 264,200 gallons (1,000 m^3) per hour when the generators are in operation.

Firefighting System Testing Water

The firefighting system would be tested annually utilizing seawater. The volume of seawater to be used and discharged for testing of the main system would be approximately 105,680 gallons (400 m^3) per year.

The total firefighting water demand for the FSRU is estimated to be 634,000 gallons (2,400 m^3) per hour. Four firefighting water pumps would be installed, each of which would be utilized at 50 percent capacity. Therefore, each pump would require 317,000 gallons (1,200 m^3) and would be used for approximately 15 minutes each week. Consequently, the volume of seawater required for testing the firefighting water pumps would be 4.12 million gallons (15,600 m^3) per year.

Monthly testing of the 25 deluge valves would require fresh water, which is generated onboard from the submerged combustion vaporizers during the regasification process. The deluge valves would be tested using a jockey pump through a 2-inch (50 millimeter [mm]) bypass line. Each deluge valve test is assumed to take 5 minutes utilizing 1,982 gallons (7.5 m^3) of fresh water for an annual consumption of 594,450 gallons (2,250 m^3) per year. The deluge valves would also be flushed with fresh water after the annual seawater test, which would require an additional volume of 105,680 gallons (400 m^3).

Water Management Systems

Both wastewater and potable water would be generated onboard the FSRU during normal operations and in the accommodation unit, and the FSRU would have facilities for both, as described in Section 2.5.1, "Floating Storage and Regasification Unit and Mooring System." The volume of ballast water would be managed through use of a computer-controlled ballast water management system during construction and operation to maintain the vessel's draft and trim, as discussed below.

Potable Water

The Applicant would use two seawater desalination units powered by waste heat recovery from the power generator engines to produce potable water. The units would produce 132 gallons (0.5 m^3) per hour of fresh water each, from a seawater throughput of 370 gallons (1.4 m^3) per hour (assuming 70 percent efficiency). The brine discharge from the unit to the ocean would be approximately 1,981,500 gallons (7,500 m^3) per year. The brine would be discharged in accordance with a facility-specific NPDES permit issued by the USEPA.

The Applicant also plans to use some water from the submerged combustion vaporizer units to supplement desalination. This additional water would be treated using ultraviolet light (UV) in a UV oxidation unit, then filtered through a 1-micron filter, and finally filtered through an activated charcoal filter for potable water use. This method would avoid the need for storing or using chlorine gas or sodium hypochlorite on board the FSRU to treat the water to drinking standards.

Wastewater Treatment and Discharge

Gray water from showers and sinks would be collected for onboard treatment. Assuming that each crewmember used 75 gallons (0.28 m^3) per day and assuming an average crew of 30, the total volume of gray water produced would be 2,250 gallons (8.5 m^3) per day. The gray water would be treated using filtration to separate particulate matter and UV oxidation to destroy dissolved organic materials. Discharge of treated gray water to the ocean would be in accordance with a facility-specific NPDES permit issued by the USEPA. Sanitary wastes from the FSRU would also be treated aboard the FSRU, with the liquid part discharged to the ocean in accordance with the FSRU's NPDES permit. The generated sludge would be containerized for subsequent transfer to shore for disposal.

Ballast Water

The FSRU would be constantly exchanging ballast water to maintain its draft and trim during both loading of LNG from LNG carriers and export of natural gas to shore using a computer-controlled ballast water management system, which is designed to constantly monitor load conditions and either intake or discharge seawater as necessary. The ballast water would be obtained from, and discharged to, the ocean in the same location adjacent to the FSRU and no chemicals would be added; therefore, treatment of the ballast water would not be necessary. Ocean water would be pumped into ballast tanks, shifted from one tank to another to keep the vessel evenly balanced, or discharged back to the ocean, as required. The exchange of ballast water would occur at the bottom of the FSRU's hull at a depth of approximately 42.7 feet (13 m). Ballast water pumps would be screened to minimize entrainment of aquatic organisms. Two screens would be employed, a 0.5-inch (1.3 cm) mesh outer screen and a 0.25-inch (0.6 cm) mesh inner screen. The ballast tanks would be inspected annually.

The LNG carriers would come to the FSRU carrying some ballast water. According to regulations, ballast water exchanges would occur outside the 200 NM (230 mile or 370 km) limit and would be recorded and reported. While offloading their LNG cargo, the carriers would pump ballast water into their tanks to compensate for the weight of LNG discharged to the FSRU.

All ballasting operations would be in accordance with MARPOL, State, and USCG regulations and protocols.

Other

All rainwater and deck washdown water would flow through deck drains to an oil/water separator before discharge to the ocean. In addition, bilge water would be treated in the oil/water separator and would meet discharge requirements prior to discharge to the ocean.

2.5.1.3 Hazardous Materials and Lubricants Management

Hazardous materials and lubrication oil would be brought onboard in appropriate containers and stored in suitable tanks or fireproof cabinets. Waste would be hauled to shore for appropriate recycling or disposal. Materials would be managed in accordance with relevant regulations.

2.5.2 Offshore Pipeline and Associated Facilities

2.5.2.1 Operations

Normal operation of the twin subsea pipelines would be dictated by commercial flow requirements. Natural gas would flow at rates varying in accordance with delivery requirements. No chemicals would be added to the gas offshore because odorant would be added onshore. No activities would occur on Ormond Beach during operation of the offshore pipelines. The metering station and instrumentation on the FSRU and within the Reliant Energy facility at Ormond Beach would serve as part of the safety and leak-detection system.

2.5.2.2 Maintenance

The integrity of the subsea transmission pipelines would be maintained through visual inspection and maintenance pigging. Title 49 CFR 190 to 199 governs the construction, operation, and maintenance of the onshore and offshore parts of the transmission pipelines. The Applicant has prepared a preliminary 10-year plan that sets forth the surveys that would be conducted as part of the maintenance program. Annual ROV surveys of the risers, anchors, and pipeline-ending manifold are included in the overall survey program.

Leaks could be detected using a pressure and mass balance system with equipment installed at both ends of the pipelines. This system would provide both alarm and automatic shutdown signals directly to the FSRU. The FSRU crew, supply boat captains, and helicopter pilots at sea would conduct leak detection routinely. Signs of gas leaks are bubbles breaking at the surface, which can be seen in most weather conditions. Monthly routine patrols would specifically watch the sea surface. Supply boats would also carry gas detectors.

Regular pipeline maintenance would include maintenance and intelligent pigging at intervals specified by the DOT, the Applicant's standard operating procedures (SOPs), and the CSLC regulations for offshore pipelines as specified in Article 3.3 (Oil and Gas Production Regulations) Section 2132(h) (Pipeline Operations and Maintenance) or when conditions warranted. Intelligent pigs are in-line inspection tools containing instruments specifically designed to determine the condition of the pipe. The pigging would cover the entire pipeline and include the sections under Ormond Beach. However, no actual activity would occur on the beach itself.

If pigging and surveillance operations determined that there was excessive corrosion or damage to the pipelines, additional analysis would be required to determine corrective actions, up to and including replacement of pipeline segments. To conduct the pigging operations, gas would have to be vented to provide the differential pressure to drive the pig through the pipeline.

2.5.3 Shore Crossing

Operation of the pipeline would involve periodic aboveground patrol of the ROW by the Applicant for leak detection surveys, valve operations, and visual inspections. Patrolling would ensure that no activities, such as construction work that could potentially impact the integrity of the pipeline, were occurring. Periodic internal inspection of the pipeline would be conducted using an intelligent pig, which would determine the pipeline's structural integrity. If this inspection revealed any substantial deterioration of the pipeline, the affected segment would be repaired or replaced. No maintenance activities on the beach are anticipated.

2.5.4 Onshore Pipelines and Aboveground Facilities

For the onshore segments of the pipelines, maintenance would include the following:

- Visual inspection of the ROW;
- Inspection and maintenance of the corrosion-protection system;
- Pipeline identification and location for nearby third-party activities; and
- ROW clearing, access maintenance, and pipeline marker maintenance.

The intervals for the above maintenance activities would vary but would be in accordance with DOT regulations and the Applicant's SOPs. The Applicant has prepared a preliminary 10-year survey schedule that involves testing and inspection of every part of the pipeline system in compliance with the integrity management rule. (See Section 4.2.6.2 for an explanation of this rule.) Inspection activities include pig surveys and hydrostatic pressure testing.

Natural Gas Odorization

The Applicant's odorant-injection facility would be located at the onshore SoCalGas pipeline station. After the natural gas passes through the meter, a small volume of mercaptan gas would be added, as is required of all natural gas supplies. The mercaptan gas – which would likely be SpotLeak 1039 (Elf Atochem), a 50/50 mixture of tert-butylmercaptan (CAS 75-66-1) and tetrahydrothiophene (CAS 110-01-0) – has a sulfurous odor and would aid in detection of leaks by smell. SoCalGas would operate the odorant facility.

2.6 FUTURE PLANS, DECOMMISSIONING, AND ABANDONMENT

2.6.1 Floating Storage and Regasification Unit and Mooring System

The impacts of decommissioning would be evaluated in a separate Project-specific environmental document, pursuant to the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA), when the Project is no longer viable. The Applicant's stated Project design life is 40 years.

The FSRU would operate as long as it remains in compliance with Federal regulations and the conditions of the license. The FSRU would be inspected annually by a classification society with a special survey by the classification society after five years and every five years thereafter.

Upon decommissioning, the FSRU would be removed from the mooring point and towed to a shipyard to be overhauled and recertified or to be scrapped and salvaged as appropriate. Before removal from the site, all gases would be removed from the entire FSRU, including LNG in the Moss tanks and natural gas from the process, mooring, riser, and pipeline systems. Depending on the component or system, the gases would be purged using inert gas followed by purging and ventilating with air or flooding with water; any necessary permits would be acquired. The flexible risers and the mooring legs would be disconnected from the FSRU bow turret and attached to a marker/pickup buoy. The FSRU would then be towed away using ocean-going tugs.

Ocean floor anchors would be removed or left in place, depending on anchor type, ocean floor environmental conditions, and regulatory requirements applicable at that time. Mooring cables, the mooring turret, flexible risers, and the pipeline-end manifold would be removed and brought to shore for final salvage or other appropriate disposal.

2.6.2 Offshore Pipelines

In both Federal and State waters, the pipelines would be evaluated to determine whether removal or abandonment would provide the most environmental benefit. Within State waters, the CSLC would determine whether or not the pipelines would need to be removed from the lease premises. Subsea pipeline abandonment would begin with pigging the line to remove any debris, scale, or other materials. If the pipelines were to be removed, they would be cut, raised to a salvage barge, and brought to shore; if not, they would most likely be filled with an inert gas and sealed before being abandoned in-place. The subsea pipelines within State waters that were drilled using HDD would also most likely be filled with an inert gas, sealed, and abandoned in-place.

2.6.3 Shore Crossing and Onshore Pipelines and Facilities

When the pipelines were no longer required they would be abandoned in-place or removed in accordance with agency requirements. If abandoned in-place, the pipelines would be cleaned to remove any liquids, filled with an inert gas, and sealed.

The onshore meter, the main-line valve, the odorant injection facility, and any other aboveground facilities would be removed and scrapped or salvaged as appropriate.

2.6.4 References

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